Tiverton is growing. Since the inception of our new strategy in 2001, we have grown our production base by 360%. 2003 propelled us by giving us a solid base on which to grow further. We have increased our drilling program for 2004, we have increased our drilling inventory, production, and reserve base. 2004 is going to be a great year for achieving...

More

TIVERTON

2003 Annual report

The 360 percent figure on the cover is calculated by comparing the December 31, 2003 exit production rate of approximately 1300 Boepd to 361 annualized Boepd in 2001.

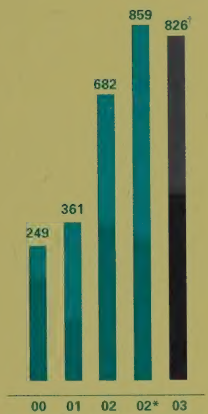
More drilling

Tiverton participated in the drilling of 19 wells (14.59 net) achieving a drilling success rate of 98% on a net basis.

Highlights

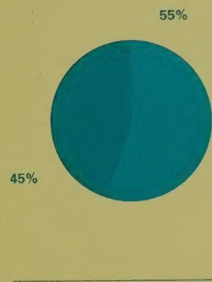
	Year Ended December 31, 2003	Nine Months Ended December 31, 2002
Financial overview ($, except share amount)		
Revenue, net of royalties	9,959,795	6,303,577
Cash flows from operations	3,842,127	2,889,010
Per share – basic and diluted	0.05	0.05
Net income	147,313	501,409
Per share – basic and diluted	0.00	0.01
Capital expenditures	12,408,885	7,254,980
Proceeds on dispositions	647,227	–
Bank debt	4,550,716	1,888,068
Working capital	(8,607,943)	(3,866,070)
Common shares outstanding – weighted average (mil)	76.3	74.7
Common shares outstanding – diluted (mil)	90.4	80.9
Operating		
Average prices ($Cdn)		
Oil and liquids price ($/Bbl)	35.33	33.64
Gas price ($/Mcf)	7.06	4.66
Boe ($/Boe)	39.14	31.03
Daily production		
Oil and liquids (Bbl)	375	437
Gas (Mcf)	2,706	2,529
Barrels of oil equivalent per day (Boe @ 6:1)	826	859
Barrels of oil equivalent per day (Boe @ 6:1) – exit rate	1,300	1,009

Volumes are converted in this Annual Report based on 6 Mcf's of gas to 1 barrel of oil equivalent (6:1).



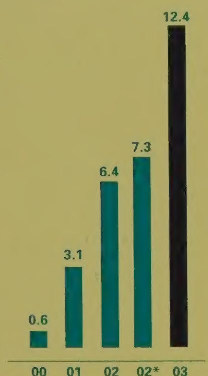
Production (Boepd)

OIL & NGLs GAS

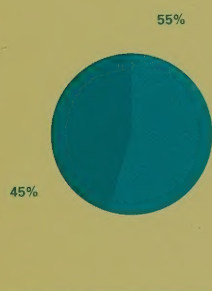


Production

OIL & NGLs GAS



Capital Expenditures ($MIL)



Proved Reserves

OIL & NGLs GAS

* Nine months ended December 31

† Exit production is approx. 1300 Boepd

Tiverton continued to grow through the drill bit in 2003.

The Company's ongoing strategy is to create a large inventory of internally generated, high quality prospects; with all seismic, land acquisition and drilling activity focused in a Southeastern Alberta core area.

Tiverton discovers hydrocarbons through the early integration of detailed geological and geophysical mapping in areas with year round access, affordable drilling, available land, and high quality production. This early integration means more efficient land acquisition, a shorter time frame from initial conception to drilling of prospects, resulting in high drilling success.

Highlights

- Increased production exit rate by 29% to approximately 1300 Boepd
- Participated in 19 wells (14.59 net)
- Capital expenditures of $12.4 million
- Raised $3.3 million in equity
- Drilling success of 98% on a net basis
- Increased seismic data base by 90 square kilometers of 3D seismic
- Drilled ten wells and built a 750 Bopd facility at Galahad which came on production in late December

Capital expenditures in 2003 were $12.4 million, the largest in the Company's history. Tiverton participated in the drilling of 19 wells (14.59 net), and achieved a drilling success rate of 98% on a net basis. Five gas wells (2.35 net), 13 oil wells (12 net) and one dry (.25 net) were drilled. Tiverton operated 14 of these wells. Fifty percent of the capital expenditures incurred were in the Galahad area where 10 wells were drilled and a 750 Bopd facility was built to handle production from the wells and future development wells. The other major areas receiving capital expenditures during the year were Alderson-Princess – 17% and Manyberries – 12%.

More progress

Tiverton continues to pursue a strategy of creating a large inventory of internally generated, high quality prospects

For the fourth year in a row, Tiverton's exit rate of production increased. The 2003 exit rate was approximately 1300 Boepd, an increase of 29% compared to 2002. The increase in exit rate is due to the commencement of production at Galahad in late December. Production is now stabilized in Galahad, which is producing approximately 600 Bopd.

During the last part of the year a number of significant regulatory changes were adopted including the Securities Act, Occupational Health and Safety Act, Energy and Utilities Board Guidelines, Accounting policies as well as New Standards of Disclosure for Oil and Gas Activities NI 51-101 among others. A significant impact of these changes is to transform the responsibility and accountability of directors and officers. It is unclear as to the overall effect on small public exploration companies. However, as an on going process, Tiverton is moving forward towards compliance in each area.

For 2004, the plan remains the same. Tiverton will continue to grow production and reserves by drilling and by developing an inventory of internally generated high working interest projects in the core area. Capital expenditures for the year ending December 31, 2004 are budgeted in excess of $10 million. The majority of the expenditures will be spent in the Galahad and Alderson-Princess areas and our goal is to exit 2004 at 1700 Boepd.

D. Blake Lowden
President
April 28, 2004

After establishing a new growth strategy in 2001, Tiverton selected East Central Alberta as its focus area. This part of the Western Canadian Sedimentary Basin typically has medium and light oil and natural gas reserves, multi-zone potential at shallow depths, year round access, a well developed infrastructure of pipelines and facilities, as well as opportunities for high reward exploration. The success of the company's 2003 drilling program demonstrated many of these attributes.

Tiverton has continued to pursue a strategy of creating a large inventory of internally generated, high quality prospects. The geologic opportunities identified are supported with the simultaneous acquisition of 3D seismic and followed by aggressive and usually successful land acquisition. Tiverton's strategy is to match high quality geologic leads with high quality 3D seismic early in the exploration process. This early integration of geology and 3D seismic results in efficient land acquisition, a shorter time frame from initial conception to drilling of prospects (usually six months), and high drilling success for both exploration and development wells. Tiverton will continue to increase its inventory of drillable prospects, primarily at 100% working interest.

Tiverton maintains an extensive seismic database with over 10,000 km of 2D seismic and 372 square kilometers of 3D seismic data. This database provides a valuable asset to the exploration team and is critical in selecting the best land and exploration drilling locations. During 2003, over 60 square kilometers of new 3D was acquired.

Tiverton continues to focus heavily on its existing producing properties in order to maximize productive potential. The Company strives to obtain the best engineering and operational expertise to ensure that all properties are optimized. Emphasis is placed on lowering operating costs and maximizing production volumes, as well as identifying low risk growth opportunities.


Southeastern Alberta
Core Area
Bellshill/Galahad
Greater Provost
Alderson/Princess
Manyberries
Alberta


Manyberries, Alberta
• Locations
R4W4


Alderson/Princess, Alberta
• Locations
T19

Manyberries

- High working interest
- Tiverton operated
- 8 sections of land
- 3D coverage on all lands
- 4 untested seismic features

2003 was a difficult year for the Manyberries property. Declining reservoir pressure resulted in significant operational problems for the producing wells. Original mapping suggested that the existing disposal well was sufficient to maintain reservoir pressure for the entire pool; however, it now appears that the pool is split into two separate pods. The 8-3 disposal well is supporting the 2-3 producer well while the 3-3, 6-3, and 10-3 wells currently have no pressure support. With reduced pressure the wells have encountered problems with sand production resulting in significant down time. Tiverton is in the process of implementing a water flood system for the entire property, which should be completed in Q2 2004 with increased production being realized immediately thereafter. With an effective water flood in place, Tiverton will be well positioned for continued growth from additional drilling on the property.

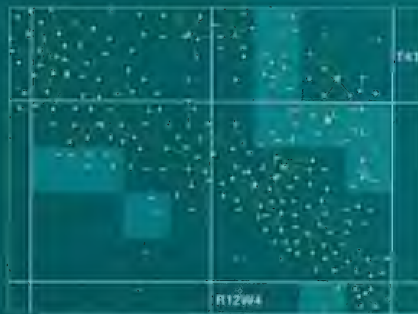
Alderson/Princess

- High working interest
- Tiverton operated
- Multi-zone potential
- Extensive 3D coverage
- Large land base

Since entering the Alderson/Princess area in 2001, Tiverton has shot five 3D seismic programs and drilled nine wells; this resulted in four oil wells, three gas wells, two dry holes, and four new pools. Tiverton currently has an interest in 35 sections of land with 23 being covered with proprietary 3D. Tiverton plans an aggressive drilling program for these lands in 2004 including locations targeting the high impact Nisku zone. The multi-zone potential of this region continues to make it an attractive core property with numerous opportunities identified for future exploration, development drilling, and continued growth.

Bellshill, Alberta

Optimization



Galahad, Alberta

• Locations

Provost, Alberta

• Locations
★ Prospects

Bellshill Lake

- Approximately 100% working interest
- Tiverton operated

The Bellshill property is a mature oil producing property which continues to produce a stable flow of oil. Efficiency and through-put are critical factors in the properties operation. In order to maximize Tiverton's opportunities a larger water handling system is being installed allowing for higher volumes and increased oil production. Additional gas compression is also being installed to maintain gas production currently being conserved.

Galahad

- Approximately 100% WI
- Tiverton operated
- Production over 500 bbls/d
- Significant upside remaining

In the Galahad area, numerous oil pools have been discovered with an aerial extent of 40 to 320 acres. These pools have recovered between 500,000 and 1,500,000 Bbls of high quality oil. Galahad has become one of Tiverton's star properties after a very successful 10 well drilling program during 2003. The Galahad property was initially purchased while producing 20 Bbls/d. A new extensive 3D was shot and the size of the pool identified. Delineation drilling began in the summer of 2003, and with the success from these wells an aggressive drilling program began late in the year. Construction of a new battery site was also completed in Q1 2004 and production is currently approximately 600 Bbls/d. Significant potential remains for this property and drilling should resume in early Q3 2004. The 3D seismic also identified three new and separate structural features similar in size to the existing pool and in close proximity to the battery site. These lands were subsequently acquired from the crown (100%WI), and exploration drilling should commence in early Q3 2004. Each of the structural features has the potential to contain 500-1000 MSTB of recoverable oil. Tiverton's new battery site has enough capacity to handle future growth from the existing pool and can easily be increased as needed with exploration success in the general area. Using the existing facility for potential new pools will reduce the overall cost per flowing barrel as well as reduce the time until production. Gas conservation is currently being evaluated and it is expected that the solution gas will be tied in during Q3 2004.

Greater Provost

The Greater Provost area is one of Tiverton's future growth areas where the use of 3D seismic in conjunction with geological leads will generate significant opportunity to find new pools. Tiverton has acquired over 50 square kilometers of 3D seismic, primarily over open crown land. Based on the seismic interpretation, land was acquired on nine separate prospects. One well was drilled resulting in a Colony gas producer. Further exploration drilling will occur in Q3 2004. One property was sold in this area.

Nevis

At Nevis, Tiverton holds a 50% working interest in a Mannville oil pool and 37% in the Belly River. One successful gas well was drilled for Belly River in 2003 and a second is planned for Q3 2004. A reservoir study is being performed to determine the viability of a water flood for the Mannville oil pool which could increase current production.

West Five Properties

Tiverton has significant land holdings and some high quality long life reserve gas holdings west of the fifth meridian in Alberta. The current inventory includes land in Paddle River, Willesden Green, Mahaska, Copton, Whitecourt, Morse, Shadow, and Burnt Timber. These properties are at various stages of development and some are currently producing. However, with Tiverton's focus placed on west four lands, its west five lands have been made available to industry. One minor property was sold and the Company has taken an active role in encouraging industry partners to review its other lands. During 2003, six new wells were drilled on Tiverton's lands at no cost to the Company, while adding minor new production. This active farm out approach will continue during 2004.

Reserves

The corporate reserve estimates, dated January 1, 2004 were prepared by the independent firm of Paddock Lindstrom & Associates Ltd. ("PLA") in accordance with the definitions set out under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). PLA also prepared the reserve estimates in 2002. Total proved reserves as at December 31, 2003 decreased marginally to 2.17 million Boe compared to 2.18 million in 2002. Total proved and probable additional reserves at December 31, 2003 increased 11% to 2.83 million Boe compared to 2.56 million in 2002.

Comparability of Reserve Information

The change to proved and probable reserve definitions implemented in NI 51-101 for the year ended December 31, 2003 may make reserve quantity and value comparisons to prior years difficult. The proved plus risked probable reserves presented in 2002 were considered to be a reasonable estimate of the reserves that would actually be recovered and are somewhat comparable to the proved plus probable reserves calculated under NI 51-101. For the 2003 presentation, where comparisons of the 2003 proved plus probable reserves are made with prior years, the comparison should be to the proved plus risked probable reserves.

Company Gross Reserves

NI 51-101 requires disclosure of "Company Gross" reserves that are defined as working interest reserves before deduction of royalties and without including any royalty interest of the the company.

More production

At 1300 Boepd, Tiverton's exit rate of production increased for the fourth year in a row.

The "Company Gross" or working interest reserves are summarized in the following table:

	Light and Medium Crude Oil	Natural Gas Liquids	Natural Gas	2003 Boe	2002 Boe
	(Mbbls)	(Mbbls)	(Mmcf)	(Mboe)	(Mboe)
Proved					
Developed producing	669	24	4,161	1,387	1,672
Developed non-producing	30	18	2,778	511	355
Undeveloped	234	–	211	269	155
Total proved	933	42	7,150	2,167	2,182
Probable	397	9	1,564	667	391
Total proved and probable	1,330	51	8,714	2,834	2,563

A significant portion of the Company's production and reserves are related to the Galahad area, which commenced production in December. The Company believes, given the limited production history and taking into account the effect of NI 51-101, full reserves will be more accurately reflected in the future.

Net Present Value of Reserves

The Company's crude oil, natural gas and natural gas liquids reserves were evaluated using PLA's product price forecasts effective March 1, 2004 including the Alberta Royalty Tax Credit ("ARTC") prior to the provision for income taxes, interest, debt service charges and general and administrative expenses.

Forecasted prices and costs	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	18,717	15,685	13,762	12,408	11,381
Developed non-producing	7,157	5,445	4,367	3,632	3,101
Undeveloped	2,064	1,716	1,446	1,233	1,063
Total proved	27,938	22,846	19,575	17,273	15,545
Probable	8,116	5,585	4,218	3,359	2,766
Total proved and probable	36,054	28,431	23,793	20,632	18,311

Pricing Assumptions

The March 1, 2004 pricing forecasts presented below have been prepared by PLA. These prices have been utilized in determining the reserves and cash flow forecasts on page 16.

Year	Crude Oil WTI	Crude Oil Edmonton Light	Natural Gas AECO-C	Inflation Rate
	($US/Bbl)	($Cdn/Bbl)	($Cdn/MMBtu)	(%/Year)
2004	30.00	38.94	6.00	2.00
2005	27.50	35.58	5.31	2.00
2006	25.50	32.90	4.83	2.00
2007	25.00	32.21	4.87	2.00
2008	25.50	32.85	4.92	2.00
2009	26.01	33.51	4.96	2.00
2010	26.53	34.18	5.01	2.00
2011	27.06	34.86	5.05	2.00
2012	27.60	35.56	5.15	2.00
2013	28.15	36.27	5.26	2.00
2014	28.72	37.00	5.36	2.00
2015	29.29	37.74	5.47	2.00
2016	29.88	38.49	5.58	2.00
2017	30.47	39.26	5.69	2.00
2018	31.08	40.05	5.80	2.00

TIVERTON

Net Present Value of Reserves - Constant Pricing and Costs Including ARTC

Forecasted prices and costs ($000's)	Undiscounted	Discounted at 5%	Discounted at 10%	Discounted at 15%	Discounted at 20%
Proved					
Developed producing	25,958	21,255	18,321	16,263	14,713
Developed non-producing	10,060	7,500	5,948	4,909	4,167
Undeveloped	3,587	2,918	2,414	2,027	1,724
Total proved	39,605	31,673	26,683	23,199	20,604
Probable	12,039	8,265	6,208	4,904	4,006
Total proved and probable	51,644	39,938	32,891	28,103	24,610

The December 31, 2003 constant oil and gas prices used in the above forecast are Edmonton sweet oil $40.92 Cdn. per barrel and gas at AECO-C $6.08 Cdn per Mcf. No escalations have been applied to future operating and capital costs throughout the forecast period.

Reserve Reconciliation

The following table details the Company Gross reserves by principal product type.

Proved reserves	Light and Medium Crude	Natural Gas Liquids	Natural Gas	Boe
	(Mbbls)	(Mbbls)	(Mmcf)	(Mboe)
December 31, 2002	794	52	8,013	2,182
Production	(131)	(5)	(982)	(300)
Additions	472	3	1,922	795
Divestitures	(2)	(1)	(418)	(72)
Technical revisions	(200)	(7)	(1,385)	(438)
December 31, 2003	933	42	7,150	2,167

Proved plus probable	Light and Medium Crude	Natural Gas Liquids	Natural Gas	Boe
	(Mbbls)	(Mbbls)	(Mmcf)	(Mboe
December 31, 2002	971	58	9,210	2,563
Production	(131)	(5)	(982)	(300)
Additions	568	4	2,285	953
Divestitures	(2)	(2)	(968)	(164)
Technical revisions	(76)	(4)	(831)	(218)
December 31, 2003	1,330	51	8,714	2,834

Finding and Development Costs

NI 51-101 specifies how finding and development ("F&D") costs should be calculated if reported. NI 51-101 requires that the exploration and development costs incurred in the year along with the change in estimated future development costs be aggregated and then divided by the applicable reserve additions. The calculation specifically excludes the effects of acquisitions and dispositions on both reserves and costs.

The calculations of the Company's F&D costs are noted in the table below. The calculations are based on the Company's net reserves which are defined as those reserves accruing to the Company after all interests owned by others including Crown and Freehold royalties have been deducted plus the Company's royalty interest reserves.

	Exploration & Development Costs	Change in Future Development Costs	Total Costs	Reserve Additions	F&D Costs
Proved	12,408,885	981,000	13,389,885	795,000	16.84
Proved plus probable	12,408,885	93,000	12,501,885	953,000	13.12

Reserve Life Index

The Company's reserve life index is calculated effective as of December 31, 2003, based on net reserves and net production to the Company. The reserve life index for proved plus probable reserves for the end of 2003 was 8.3 years as compared to 7.2 for 2002. The reserve life index for proved reserves for 2003 was 6.8 years as compared to 6.1 years for 2002.

Reserve Replacement

The Company's 2003 capital investment program replaced production by a factor 2.2 times on a proved basis and 2.6 times on a proved plus probable basis.

More opportunity

Tiverton will continue to grow production and reserves by drilling and by developing an inventory of internally generated high working interest projects in the core area.

Early integration of geology and 3D seismic has resulted in efficient land acquisition, a shorter time frame from initial conception to drilling of prospects, and high drilling success.

Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and the MD&A for the year ended December 31, 2003 and for the period ended December 31, 2002 contained in this annual report. Where amounts are expressed on a per barrel of oil equivalent basis (Boe), gas volumes have been converted to oil equivalence at six thousand cubic feet per barrel.

The Company changed its fiscal year end from March 31 to December 31 effective December 31, 2002. The Company's consolidated financial statements have been presented for the year ended December 31, 2003 and for the nine months ended December 31, 2002.

The MD&A uses the terms "cash flow from operations" and "cash flow per share" which are not recognized measures under Canadian generally accepted accounting principles (GAAP). Management believes that in addition to net earnings, cash flow is a useful supplemental measure as it provides an indication of the results generated by the Company's principal business activities prior to the consideration of how those activities are financed or how the results are taxed. Investors are cautioned, however, that this measure should not be construed as an alternative to net earnings determined in accordance with GAAP as an indication of the Company's performance. The Company's method of calculating cash flow may differ from other companies, and accordingly, it may not be comparable to measures used by other companies. The Company calculates cash flow from operations prior to the change in non-cash working capital related to operating activities.

Revenue

The Company derives its revenue from the production and sale of crude oil, natural gas liquids and natural gas. Average daily volumes for the year ended December 31, 2003 declined on a Boe basis by 4% to 826 Boepd from 859 Boepd in 2002. Average oil and liquids prices for the year increased 5% to $35.33 from $33.64 in 2002. Average natural gas prices increased 51% to $7.06 from $4.66 in 2002.

Production revenue for year the ended December 31, 2003 was allocated 56% from the sale of natural gas and 44% from the sale of oil and liquids. In December approximately 475 Bbls/d of oil production were put on stream which will change the ratio of natural gas to oil and liquids in the future.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Oil and natural gas sales, net of royalties	9,896,593	6,207,107
Processing, seismic and other income	63,202	96,470
	9,959,795	6,303,577
Average oil and liquids price	35.33	33.64
Average gas price	7.06	4.66
Production – Boepd	826	859

Royalties

Royalties include payments made to the Crown, freehold owners and third parties. Reported royalties include credits received through the Alberta Royalty Tax Credit (ARTC) program. Royalties as a percentage of revenue increased by 23% to 16% from 13% in 2002.

During 2003, 59% of the total royalties were paid to the Alberta provincial government with the remainder paid to freehold owners and third parties. Royalties payable to the Province of Alberta on qualifying properties are reduced through the ARTC program. The Company received $419,505 through the ARTC program in 2003.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Royalties	1,949,995	953,968
% of Oil & gas sales	16	13
Per Boe	6.46	4.04

Operating

Operating costs on a Boe basis increased 63% to $14.73 as compared to $9.05 in 2002. The increase is due to unusually high operating costs at the Company's main oil producing properties of Galahad, Bellshill and Manyberries. At Manyberries, operating costs were $10.43 per barrel higher than 2002 costs. Bellshill increased by $3.27 per barrel as compared to 2002. Galahad is a new property and experienced extraordinarily high operating costs associated with stabilizing production.

The Galahad property is now stabilized with the first quarter 2004 operating costs at an acceptable $8.36 per barrel. The Galahad production in the first quarter of 2002 accounted for 73% of the Company's oil production. The high volumes and low operating costs will reduce operating costs and operating netbacks in the future. Projects are also underway at Manyberries and Bellshill to lower the operating costs and positive results will hopefully be seen in the second quarter 2004.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Operating costs	4,443,566	2,138,139
Per Boe	14.73	9.05

Operating Netback

On a Boe basis operating netback increased 5% to $18.08 as compared to $17.22 in 2002. Commodity prices increased by 26 %, however this was offset by a 63% increase in operating expenses on a Boe basis.

The Company expects increased operating netback in the future as a result of the significant increase in oil production from the Galahad property and low operating costs.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Oil and natural gas sales, net of royalties	9,896,593	6,207,107
Operating costs	4,443,566	2,138,139
Operating netback	5,453,027	4,068,968
Operating netback per boe	18.08	17.22

General and Adminstrative

Gross general and administrative expenses ("G&A") on a Boe basis increased 13% to $7.51 per Boe from $6.67 in 2002. An increase in exploration staff, consultants and related expenses to ensure the continued development of seismically supported quality prospects is the main reason for the increase.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Gross G&A	2,265,226	1,576,125
Capitalized G&A	(797,114)	(463,803)
Net G&A	1,468,112	1,112,322
Per Boe – gross	7.51	6.67
Per Boe – net	4.87	4.71
Number of employees at period end	11	10

Depletion and Depreciation

Depletion and depreciation expense is an accounting measure of the amortization of the finding, development and other related capital costs over the life of the Company's reserves. Capital costs include the net book value of historical costs incurred and estimated future expenditures to develop the proved reserves. The expense is calculated using the ratio of production volumes to proved reserves and applying the ratio to the net book value of the capital costs.

Site restoration expense is calculated on a unit of production basis and is a provision for the estimated future costs to abandon and reclaim producing or previously producing wells and facilities. The provision is based on the ratio of production volumes to proved reserves.

Depletion and depreciation expenses on a Boe basis increased 17% to $10.80 per Boe from $9.25 in 2002. The increase is attributed to significant growth in the asset base and a slight decline in proved reserves.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Depletion and depreciation	3,257,942	2,185,372
Per Boe	10.80	9.25

Income Taxes

Current income taxes are solely comprised of the Large Corporations Tax. The increase is due to the higher capital base of the Company attributable to the equity financing completed during 2003.

Future income taxes have increased over 2002 as a result of a valuation allowance recorded for successor tax pools that will not likely have a benefit in the future.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Current	59,786	46,744
Future income taxes	337,000	184,000
	396,786	230,744

Tax Pools – December 31, 2003	
Canadian exploration expense	6,001,818
Canadian development expense	7,236,448
Canadian oil and gas property expense	2,924,722
Undepreciated capital costs	7,074,334
Share issue expenses	461,155

Cash Flow

Cash flows from operations on a Boe basis increased by 4% to $12.74 as compared to $12.23 for 2002. On a Boe basis commodity prices increased 26% which was offset by an increase in royalties of 59% and an increase in operating expenses of 63%. Lower operating expenses were incurred in the first quarter of 2004 and continued reductions are expected in the future.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Cash flows from operations	3,842,127	2,889,010
Per Boe	12.74	12.23
Per share – basic and diluted	0.05	0.05

Net Income

Commodity prices on a Boe basis increased by 26%; however, this was offset by increases in all of the Company's expense categories.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Net income	147,313	501,409
Per Boe	0.49	2.12
Per share – basic and diluted	0.00	0.01

Capital Expenditures

Capital expenditures of $12,408,885 were financed through a combination of cash flow, proceeds from the issue of common shares, proceeds from the disposition of properties and increase in bank debt.

$	Year ended December 31, 2003	Nine months ended December 31, 2002
Exploration and development	8,177,938	4,149,702
Facilities	3,591,726	1,999,078
Land	588,664	1,075,555
Other	50,557	30,645
	12,408,885	7,254,980

Liquidity and Capital Resources

Capital expenditures of $12,408,885 were funded 31% by cash flow, 26% from the issue of equity and 43% by the increase of bank debt and working capital deficiency.

The Company has a revolving demand loan facility with a Canadian chartered bank that provides borrowing of up to $6,795,000 as at December 31, 2003. The bank debt at December 31, 2003 is $4,550,716 as compared to $1,888,068 at December 31, 2002. At December 31, 2003, Tiverton's working capital deficiency which includes bank debt was $8,607,943. In January, 2004 the Company completed an 8% convertible, redeemable unsecured Debenture financing in the amount of $3,480,000.

Equity

During the year ended December 31, 2003, the Company issued the following common shares:

$	Number of Shares	Net Stated Value
Issued pursuant to private placements	8,075,026	3,119,523
Exercise of stock options	1,137,500	215,125
	9,212,526	3,334,648

During the year ended December 31, 2003, the Company repurchased 48,000 common shares pursuant to a Normal Course Issuer Bid. The total cost for these shares was $15,679, which equates to an average cost of $0.33 per share.

At December 31, 2003, the Company had 83.7 million shares outstanding. Including the 5.5 million options outstanding under the Company stock option plan, the Company's diluted balance of shares outstanding is 89.2 million shares at December 31, 2003.

New Accounting Standards

Asset retirement obligations

In 2003 the CICA approved Section 3110 "Asset Retirement Obligations," which requires liability recognition for retirement obligations associated with the Company's property and equipment. The obligations are initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. Section 3110 is effective for fiscal years beginning on or after January 1, 2004. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Full cost accounting

In 2003, the CICA issued Accounting Guideline 16 "Oil and Gas Accounting - Full Cost" (AcG-16), to replace AcG-5. The new guideline is effective for fiscal years beginning on or after January 1, 2004. The most significant change between Acg-16 and AcG-5 is that Acg-16 limits the carrying value of petroleum and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and probable reserves using future price forecasts and costs discounted at a risk-free rate. This differs from the current cost recovery ceiling test under AcG-5 that uses undiscounted cash flows, constant prices and costs, less general and administrative, income taxes and financing costs. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Stock-based compensation

The CICA issued an amendment to Section 3870 "Stock-based Compensation and Other Stock-based Payments", whereby stock options granted to employees, officers and directors on or after January 1, 2002, are accounted for using the fair value method. Under this method, stock-based compensation expense is recognized when an option is granted, based on the fair value of the option on the date of grant. This standard provides for the retroactive adoption effective January 1, 2004. The Company is currently evaluating the impact of this standard on its consolidated financial statements.

Business Risks

Tiverton's production and exploration activities are concentrated in the Western Sedimentary Basin, primarily in Alberta, where activity is highly competitive and includes a variety of different sized companies ranging from smaller junior producers to the much larger integrated petroleum companies. Tiverton is subject to the following types of business risks: finding economic oil and gas reserves and recovering those reserves; securing access to markets for production; commodity price and interest rate fluctuations; changes to income tax and royalty regulations; and changes to environmental and other government regulations.

The company reduces these business risks by employing highly competent professional staff who use leading edge technology to aid in performing careful risk/reward analysis of each prospect from a geological, geophysical and engineering perspective. The Company also focuses on a few core areas where the staff have strong existing knowledge and expertise. In addition the Company controls and operates all its core properties. The Company maintains a comprehensive insurance program that insures liability and property consistent with industry practice. The program is designed to mitigate risks and protect against significant loss. However, the Company is not fully insured against these risks, nor are all such risks insurable. The Company operates in a manner that minimizes the impact of the Company's activities on the environment.

Quarterly Financial Information

Year ended December 31, 2003 ($)	Q4	Q3	Q2	Q1
Revenue before royalties	2,637,932	2,727,703	2,899,377	3,644,778
Cash flow from operations	632,601	841,550	750,346	1,617,630
Cash flow from operations per share				
– basic and diluted	0.01	0.01	0.01	0.02
Net income (loss)	(490,676)	69,353	46,429	522,207
Net income (loss) per share				
– basic and diluted	(0.01)	0.00	0.00	0.01
Boe/day	833	819	786	840

Nine months ended December 31, 2002 ($)	Q3	Q2	Q1
Revenue before royalties	3,222,183	1,932,141	2,006,751
Cash flow from operations	1,270,780	677,345	940,885
Cash flow from operations per share			
– basic and diluted	0.02	0.01	0.02
Net income	179,906	77,121	244,382
Net income per share			
– basic and diluted	0.01	0.00	0.00
Boe/day	797	792	777

Commodity prices in Q4 2003 were the lowest of the year and this adversely effected net earnings and cash flow. Production for the fourth quarter was up marginally from the third quarter of 2003.

The fourth quarter saw the Company spend one third of its capital expenditures for the year with the majority of the expenditures being spent in the Galahad area. Eight wells were drilled and a 750 Bbl/d facility was built to handle the production from the wells and future wells to be drilled. Wells were put on stream in late December. The exit production rate was approximately 1300 Bbls/d.

The Company incurred a loss of $490,676 in the quarter. Lower commodity prices and higher depletion expenses were the major contributors to the loss. The depletion and depreciation charges were higher due to a larger depletion base and lower reserves.

Outlook

The Company has budgeted $10 million of capital expenditures allocated to oil and natural gas exploration and development in 2004. The majority of the budget will be spent in the Galahad and Alderson-Princess areas where the potential for increased growth in daily production and reserves is significant. The first phase of 2004's program will concentrate on finding new pools in these areas with development to follow in the fall of 2004.

Forward Looking Statements

Certain information regarding the Company set forth in this document, including management's assessment of the Company's future plans and operations, contain forward looking statements that involve substantial known and unknown risks and uncertainties. These forward looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Company's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuation, imprecision of reserve estimates, environmental risks, taxation policies, competition from other producers, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal or external sources. The Company's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward looking statements will transpire or occur, or if any of them do so, what benefits that the Company will derive therefrom.

Consolidated Financial Statements
and Notes to the Consolidated Financial Statements

To the Shareholders of Tiverton Petroleums Ltd.

The consolidated financial statements of Tiverton Petroleums Ltd. were prepared by management in accordance with accounting principles generally accepted in Canada. The financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

Management has designed and maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of financial statements for reporting purposes. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. Such estimates are based on careful judgments made by management.

External auditors Collins Barrow Calgary LLP appointed by the shareholders have conducted an independent examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through its Audit Committee. The Audit Committee, which consists of primarily non-management directors, has met with the external auditors and management in order to determine that management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Audit Committee has reported its findings to the Board of Directors who have approved the consolidated financial statements.

D. Blake Lowden
President and CEO

Ward G. McLean
Vice President, Finance and CFO

To the Shareholders of Tiverton Petroleums Ltd.

We have audited the consolidated balance sheets of Tiverton Petroleums Ltd. as at December 31, 2003 and 2002 and the consolidated statements of income, retained earnings and cash flows for the year ended December 31, 2003 and for the nine months ended December 31, 2002. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the periods then ended in accordance with Canadian generally accepted accounting principles.

Collins Barrow Calgary LLP

CHARTERED ACCOUNTANTS

Calgary, Alberta

March 29, 2004

Consolidated Balance Sheets

December 31, 2003 and 2002

		December 31, 2003	December 31, 2002
Assets	**Current asset**		
	Accounts receivable and prepaid expenses	$ 1,685,962	$ 2,549,566
	Note receivable (note 4)	–	64,000
	Property and equipment (note 5)	28,985,738	20,367,784
		$ 30,671,700	$ 22,981,350
Liabilities	**Current liabilities**		
	Accounts payable and accrued liabilities	$ 5,743,189	$ 4,160,568
	Bank debt (note 6)	4,550,716	1,888,068
	Current portion of notes payable	–	367,000
		10,293,905	6,415,636
	Provision for future site restoration costs	346,915	245,988
	Future income taxes (note 7)	1,515,000	267,000
	Non-controlling interest	163,112	146,560
		12,318,932	7,075,184
Shareholders' Equity	Share capital (note 8)	13,558,692	11,283,090
	Contributed surplus (note 9)	31,320	–
	Retained earnings	4,762,756	4,623,076
		18,352,768	15,906,166
		$ 30,671,700	$ 22,981,350

Approved by the Board,

Director

Director

See accompanying notes

Consolidated Statements of Income

	Year ended December 31, 2003	Nine months ended December 31, 2002
Revenue		
Oil and natural gas sales, net of royalties	$ 9,896,593	$ 6,207,107
Processing seismic and other	63,202	96,470
	9,959,795	6,303,577
Expenses		
Production	4,443,566	2,138,139
General and administrative	1,468,112	1,112,322
Interest on notes payable and bank debt	229,524	117,362
Depletion and depreciation	3,257,942	2,185,372
	9,399,144	5,553,195
Income before income taxes and non-controlling interest	560,651	750,382
Less: Non-controlling interest in net income of a subsidiary	16,552	18,229
Income before income taxes	544,099	732,153
Income taxes (note 7)		
Current	59,786	46,744
Future income taxes	337,000	184,000
	396,786	230,744
Net income	$ 147,313	$ 501,409
Net income per share (note 10)		
Basic and diluted	$ 0.00	$ 0.01

Consolidated Statements of Retained Earnings

	Year ended December 31, 2003	Nine months ended December 31, 2002
Retained earnings, beginning of period	$ 4,623,076	$ 4,141,665
Acquisition of shares in excess of carrying value (note 8 (d))	(7,633)	(19,998)
Net income	147,313	501,409
Retained earnings, end of period	$ 4,762,756	$ 4,623,076

See accompanying notes

	Year ended December 31, 2003	Nine months ended December 31, 2002
Cash provided by (used for):		
Operating activities		
Net income	$ 147,313	$ 501,409
Add items not affecting cash		
Depletion and depreciation	3,257,942	2,185,372
Future income taxes	337,000	184,000
Compensation expense	31,320	–
Non-controlling interest	16,552	18,229
Cash flows from operations	3,842,127	2,889,010
Changes in non-cash working capital	1,083,044	7,426
	4,873,171	2,896,436
Financing activities		
Increase in bank debt	2,662,648	201,011
Proceeds on issuance of common shares, net of issuance costs	3,258,648	3,409,887
Repayment of notes payable	(367,000)	–
Repurchase of common shares	(15,679)	(55,303)
	5,538,617	3,555,595
Investing activities		
Expenditures on property and equipment	(12,408,885)	(7,029,980)
Proceeds on disposition of property and equipment	647,227	–
Site restoration and abandonment	(13,311)	(105,346)
Changes in non-cash working capital	1,363,181	683,295
	(10,411,788)	(6,452,031)
Change in cash	–	–
Cash, beginning and end of period	–	–
Income and capital taxes paid	$ 40,526	$ 25,385
Interest paid	$ 244,547	$ 103,845

See accompanying notes

Note 1 Change in Year End

The Company changed its fiscal year end from March 31 to December 31 effective December 31, 2002. The Company's consolidated financial statements have been presented for the year ended December 31, 2003 and the nine months ended December 31, 2002.

Note 2 Company Activities

The Company's activities are the exploration for and development of oil and natural gas properties in Western Canada.

Note 3 Summary of Significant Accounting Policies

The consolidated financial statements of the Company are stated in Canadian dollars and have been prepared in accordance with accounting principles generally accepted in Canada.

The significant accounting policies are summarized below:

(a) Principles of consolidation

The consolidated financial statements include, in addition to the accounts of the Company, the accounts of its wholly-owned subsidiaries, Tiverton Petroleums Inc. and Fulcrum Exploration Ltd., and its 50% owned subsidiary, McDrake Investments Ltd.

(b) Exploration and development costs

Capitalized costs

The Company follows the full cost method of accounting whereby all costs relating to the exploration for and the development of oil and natural gas reserves are initially capitalized and accumulated in cost centres by country. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead and interest directly related to exploration and development activities, and lease and well equipment. Gains or losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the related cost centre's rate of depletion and depreciation by 20% or more.

Depletion and depreciation

Costs capitalized are depleted and depreciated using the unit-of-production method by cost centre based on production volumes, before royalties in relation to estimated proved oil and natural gas

reserves as determined by independent engineers. In determining costs subject to depletion, the Company includes estimated future costs to be incurred in developing proved reserves. The cost of undeveloped land is excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties, or impairment has occurred. For purposes of the calculation, production and reserves of natural gas are converted to equivalent barrels of oil based on their relative energy content where one barrel of oil or liquids equals six thousand cubic feet of natural gas.

Future site restoration costs

Estimated future site restoration costs, net of expected recoveries, are provided for over the life of the proved reserves on a unit-of-production basis. Costs include the cost of production equipment removal and environmental cleanup based upon regulations and economic circumstances at period-end. The annual provision for future site restoration costs is included in depletion and depreciation expense and actual abandonment and site restoration expenditures are charged to the accumulated provision account as incurred.

Ceiling test

In applying the full cost method, the Company performs a ceiling test which restricts the capitalized costs less accumulated depletion and depreciation for each cost centre from exceeding an amount equal to the estimated undiscounted value of future net revenues from proved oil and natural gas reserves, based on year-end prices and costs, and after deducting estimated future general and administrative expenses, estimated future site restoration costs, financing costs and income taxes.

(c) Joint venture accounting

Many of the exploration and production activities of the Company are conducted jointly with others and accordingly these financial statements reflect only the Company's proportionate interest in such activities.

(d) Revenue recognition

Revenue from the sale of oil and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(e) Depreciation

Other assets are depreciated on the declining balance method at annual rates of 20% to 30% per annum.

(f) Income taxes

Income taxes are accounted for using the liability method of income tax allocation. Under the liability method, income tax assets and liabilities are recorded to recognize future income tax inflows and outflows arising from the settlement or recovery of assets and liabilities at their carrying values. Income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those benefits are more likely than not to be realized. Future income tax assets and liabilities are determined based on the tax laws and rates that are anticipated to apply in the year of realization.

(g) Flow-through shares

The Company, from time to time, issues flow-through shares to finance a portion of its petroleum and natural gas exploration activities. The exploration and development expenditures funded by flow-through shares are renounced to investors in accordance with tax legislation. The estimated value of the tax pools foregone is reflected as a reduction in share capital with a corresponding increase in the future income tax liability, when the qualifying expenditures are made.

(h) Stock based compensation plan

The Company has a stock based compensation plan, as described in note 9. Any consideration received by the Company on exercise of stock options is credited to share capital.

The Company uses the intrinsic value method to account for stock-based compensation costs for its directors and employees. Under this method, no compensation costs are recorded for stock options granted so long as the exercise price of the options is not lower than the market price of the Company's shares on the date of the issue.

The Company uses the fair value method to account for stock-based compensation costs for consultants. Under this method, the fair value of options granted are estimated at the date of grant using the Black-Scholes option pricing model. Compensation expense is recorded over the vesting period as general and administrative expense with a corresponding increase in contributed surplus.

(i) Net income per share

Basic net income per share is calculated by dividing net income by the weighted average number of common shares outstanding during the period. The Company applies the treasury stock method for the calculation of diluted net income per share whereby the effect of in-the-money instruments such as stock options and warrants affect the calculation. The treasury stock method assumes that the proceeds from the exercise of in-the-money stock options and warrants are used to repurchase common shares of the Company at the weighted average market price during the period.

(j) Measurement uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingencies. Such estimates primarily relate to unsettled transactions and events at the balance sheet date. Actual results could differ from those estimated.

The amounts recorded for depletion and depreciation of oil and natural gas properties, the provision for future site restoration costs and the ceiling test are based on estimated proven reserves, production rates, future oil and natural gas prices and future costs.

The amounts disclosed related to fair values of stock options issued, and the resultant income and pro forma income effects are based on estimates of future volatility of the Company's share price, expected lives of the options, expected dividends to be paid by the Company and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the consolidated financial statements for future periods could be significant.

Note 4 Change in Accounting Policy

Share purchase loan

On January 1, 2003, the Company adopted the recommendations of the Canadian Institute of Chartered Accountants as they relate to share purchase loans. Under the new recommendations, loans made to employees, officers and directors of the Company to assist in the purchase of the Company's own stock, are presented as reductions to shareholders' equity, rather than assets, unless there is substantial evidence that the borrower, and not the Company, is at risk for any decline in the price of the shares. When the loans are presented as reductions of shareholders' equity, the Company considers the shares purchased with the loaned funds to be stock options in substance.

The change in accounting policy, in the consolidated financial statements at December 31, 2003, has resulted in a decrease of $64,000 in both note receivable and share capital. Previous periods have not been restated. The 200,000 shares previously issued related to the share purchase loan are considered to be options in substance and are included in the disclosure in note 9.

Note 5

Property and Equipment

$	Cost	December 31, 2003 Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties, including exploration and development thereon	39,400,938	19,184,605	20,216,333
Lease and well equipment	12,794,184	4,110,814	8,683,370
Seismic data held for resale	291,459	291,459	–
Other	324,030	237,995	86,035
	52,810,611	23,824,873	28,985,738

$	Cost	December 31, 2002 Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties, including exploration and development thereon	31,279,026	17,004,228	14,274,798
Lease and well equipment	9,204,994	3,178,061	6,026,933
Seismic data held for resale	291,459	291,459	–
Other	273,474	207,421	66,053
	41,048,953	20,681,169	20,367,784

During the year ended December 31, 2003, the Company capitalized general and administrative expenses in the amount of $797,114 (2002 - $463,803) of total general and administrative expenses incurred of $2,265,226 (2002 - $1,576,125).

Future site restoration costs are estimated in aggregate to be $1,307,000 (2002 - $1,094,000) of which $114,238 (March 2002 - $87,142) has been charged to income in the current year.

Costs of undeveloped land amounting to $1,298,000 (2002 - $952,000) have been excluded from the depletion and depreciation calculation.

Note 6 Bank Debt

At December 31, 2003, the Company had a revolving demand loan to a maximum of $6,795,000. Interest is payable monthly at a Canadian chartered bank's prime rate plus 0.5% per annum. The loan maximum reduces by $235,000 per month commencing February 1, 2004. The loan is secured by a general security agreement, an $8,000,000 first fixed and floating charge debenture over all current and after-acquired Company assets, and a fixed charge over certain petroleum and natural gas properties. The Company must comply with certain reporting requirements and reserves-based covenants.

Note 7 Income Taxes

(a) The components of the future income tax liability at December 31, 2003 and 2002 are as follows:

$	2003	2002
Liability related to carrying amount of property and equipment and future site restoration in excess of available tax deductions	1,931,496	611,626
Attributed Canadian royalty income carryforward	(248,129)	(172,108)
Undeducted share issuance costs	(168,367)	(172,518)
	1,515,000	267,000

(b) Income tax expense differs from that which would be expected from applying the combined effective Canadian federal and provincial income tax rates of 40.62% (2002 - 42.12%) to income before income taxes. The difference results from the following:

$	2003	2002
Expected income tax provision	221,013	308,383
Increase (decrease) resulting from:		
Non-deductible crown payments, net of Alberta royalty tax credit	446,629	193,013
Resource allowance	(408,040)	(267,926)
Impact of tax rate reductions	2,265	4,369
Large corporations tax	51,151	13,800
Provincial tax deductions	(82,429)	(25,781)
Valuation allowance	122,674	–
Other	43,523	4,886
Income taxes	396,786	230,744

A valuation allowance has been recorded related to the resource tax pools on successored properties as benefits are not likely to be realized.

Corporate tax returns are subject to audit and reassessment by Canada Revenue Agency. The results of any reassessment will be accounted for in the year in which they are determined.

Note 8

Share Capital

(a) Authorized:

Unlimited number of common shares;

10,000,000 preferred shares without nominal or par value, issuable in series for aggregate consideration not exceeding $100,000,000.

(b) Issued:

	2003		2002	
Common shares	**Number**	**Stated Value**	**Number**	**Stated Value**
Balance, beginning of period	74,737,808	$ 11,283,090	58,905,499	$ 7,766,508
Issued for cash (note 8[c])	8,075,026	3,250,475	14,029,309	3,542,600
Exercise of options (note 9)	1,137,500	215,125	1,100,000	165,000
Purchase of petroleum and natural gas properties	–	–	950,000	225,000
Purchased pursuant to a normal course issuer bid (note 8[d])	(48,000)	(8,046)	(247,000)	(35,305)
Share purchase loan (note 4)	(200,000)	(64,000)	–	–
Tax effect of flow-through share expenditures	–	(987,000)	–	(208,000)
	83,702,334	13,689,644	74,737,808	11,455,803
Less: Share issuance costs (net of income taxes of $76,000 [2002 – $125,000])		130,952		172,713
Balance, end of period	83,702,334	$ 13,588,692	74,737,808	$ 11,283,090

(c) Included in common shares issued for cash during the year ended December 31, 2003 are 8,075,026 (2002 – 12,124,948) flow-through common shares issued for gross proceeds of $3,250,475 (2002 - $3,142,600). Income tax deductions of $3,250,475 were renounced to subscribers effective December 31, 2003, with the related qualifying expenditures to be incurred prior to December 31, 2004.

At December 31, 2002, the Company had incurred $493,978 in qualifying expenditures and had $2,648,622 in expenditures left to incur. The tax effects of these renouncements of $208,000 have been recorded as a reduction in share capital. The remaining expenditures were incurred in 2003 and the resultant tax effect of $967,000 has been recorded as a reduction in share capital.

(d) Pursuant to a Normal Course Issuer Bid, the Company acquired 48,000 (2002 – 247,000) common shares at an average price of $0.33 (2002 - $0.22) per share. The excess cost of reacquisition over stated value in the amount of $7,633 (2002 - $19,998) has been charged to retained earnings.

Note 9

Stock Based Compensation Plan

The Company has a stock option plan that provides for the issuance of options to directors, employees and consultants. Under the plan, the exercise price of options granted cannot be less than the closing market price on the day immediately preceding the day of the grant. The options contain a provision whereby 25% vest immediately and the remaining vest equally over three years and expire five years from the date of the grant. The exercise price of each option equals the market price of the Company's shares at the date of grant.

Under the stock option plan, the Company may grant options to its directors, employees and consultants for up to 6,612,500 (2002 – 4,800,000) common shares. The shareholders of the Company approved an increase in the maximum to 7,500,000.

A summary of the status of the Company's stock option plan as of December 31, 2003 and 2002, and changes during the periods then ended are as follows:

	2003		2002	
	Number of Options	Weighted Average Exercise Price	Number of Options	Weighted Average Exercise Price
Outstanding, beginning of period	4,900,000	$ 0.18	4,800,000	$ 0.16
Granted	1,800,000	$ 0.22	1,400,000	$ 0.22
Share purchase loan (note 4)	200,000	$ 0.32	–	–
Exercised	(1,137,500)	$ 0.19	(1,100,000)	$ 0.15
Cancelled/expired	(237,500)	$ 0.24	(200,000)	$ 0.24
Outstanding, end of period	5,525,000	$ 0.19	4,900,000	$ 0.18

The following table summarizes information about the Company's stock options outstanding and exercisable at December 31, 2003:

	Options Outstanding			Exercisable Options	
	Number Outstanding	Weighted Average Remaining Term (years)	Weighted Average Exercise Price	Number Exercisable	Weighted Average Exercise Price
$0.15 to $0.20	2,750,000	2.01	$ 0.16	2,750,000	$ 0.16
$0.21 to $0.32	2,775,000	4.12	$ 0.23	1,462,500	$ 0.24
	5,525,000	3.04	$ 0.19	4,212,500	$ 0.19

At December 31, 2002, the Company had outstanding 1,300,000 share purchase warrants issued to a director of the Company and to companies related by virtue of common directors and shareholders. All warrants expired unexercised in 2003.

During the quarter ended June 30, 2003, certain employees and directors were granted options to acquire 1,250,000 common shares at an average price of $0.21 per share. The aggregate fair value of these options is $181,250 under the Black-Scholes option pricing model as described below. If the fair value based method had been used, the stock based compensation costs, proforma net income and proforma net income per share would have been as follows:

$	2003	2002
Stock based compensation costs	75,000	219,000
Net income		
As reported	147,313	501,409
Pro forma	72,313	282,409
Net income per share – basic and diluted		
As reported	0.00	0.01
Pro forma	0.00	0.00

During the quarter ended June 30, 2003, 550,000 options were granted to consultants at an average exercise price of $0.22 per common share. The consultant options have an aggregate fair value of $79,200 under the Black-Scholes option pricing model as described below. The resulting compensation expense of $31,320 for the year ended December 31, 2003 has been recorded as contributed surplus.

The fair value of each option granted was estimated on the date of the grant using the Black-Scholes options pricing model with the following weighted average assumptions.

	2003		2002	
	Employees and Directors	Consultants	Employees and Directors	Consultants
Fair value of stock options granted	$ 0.15	$ 0.14	$ 0.16	–
Risk-free interest rate	4.07%	3.92%	4.00%	–
Expected life	5 years	5 years	5 years	–
Expected volatility	77.48%	77.48%	85.87%	–
Expected annual dividend per share	Nil	Nil	Nil	–

Note 10 Per Share Amounts

Net income per share has been calculated based on the weighted average number of common shares outstanding during the year of 76,264,568 (2002 – 61,871,118).

A reconciliation of the denominators for the per share calculations using the treasury stock method is outlined below:

	2003	2002
Basic weighted average shared	76,264,568	61,871,118
Effect of dilutive options	1,917,308	930,140
Diluted weighted average shares	78,181,876	62,801,258

There is no change to the numerator in the calculation of diluted per share amounts for either period.

At December 31, 2003, there were 200,000 (2002 – 1,050,000) options outstanding with a weighted average exercise price of $0.32 (2002 - $0.23), and nil (2002 – 1,300,000) warrants outstanding with a weighted average exercise price of $nil (2002 - $0.37) that have not been included in the calculation of diluted income per share as the effect would be anti-dilutive.

Note 11 Commitment

The Company has certain obligations under an operating lease for office premises. The commitment, including occupancy and operating costs, is approximately $224,028 per year which expires February 2007.

Note 12 Related Party Transactions

At December 31, 2003, amounts due to a related company by virtue of a common director and officer of $80,917 (March 2002 - $49,628) were included in accounts payable and accrued liabilities. These amounts arose in the normal course of operations as the related company is a joint venture partner in certain properties operated by the Company.

Note 13 Financial Instruments

Fair values

Fair value of accounts receivable, accounts payable and accrued liabilities and bank debt approximate their carrying values due to their short-term maturity.

Credit risk

Substantially all of the Company's accounts receivable are due from companies in the oil and gas industry and are subject to the normal industry credit risks. The carrying value of accounts receivable reflects management's assessment of the associated credit risks.

Note 14 Comparative Figures

Certain comparative figures have been reclassified to conform with the current period's presentation.

Note 15 Subsequent Event

Subsequent to December 31, 2003 the Company completed an 8% convertible redeemable unsecured Debenture financing in the amount of $3,480,000. The Debentures will mature on February 15, 2009 unless called for redemption earlier by the Company. The Debentures are convertible by the holder at any time to maturity, into 6,692,040 common shares of the Company, representing a conversion price of $0.52 per share. 3,480,000 common share purchase warrants are attached to the Debentures which entitle the debenture holders to purchase the common shares of the Company at a price of $0.60 until January 31, 2006. The Company can elect to prepay the Debenture after February 15, 2005 providing the Company's stock trades above $0.60 per share on average for a period of 22 consecutive days. As part of the compensation to the agent the Company has issued options to purchase 535,920 common shares of the Company at a price of $0.52 at any time until January 31, 2006. Interest is payable semi-annually on June 30th and December 31st of each year. The Debentures will be segregated into debt and equity components based upon their respective fair values.

Board of Directors

Michel Brusset
Calgary, Alberta, Canada

Frank J. Crothers
Nassau, Bahamas

D. Blake Lowden
Calgary, Alberta, Canada

Peter N. Thomson
Nassau, Bahamas

Management

D. Blake Lowden
President

Richard Poirier, P. Geol., MBA
Vice President, Exploration

Ward McLean, CA
Chief Financial Officer

Transfer Agent and Registrar

The CIBC Mellon Trust Company

Bank

Canadian Western Bank

Engineers

Paddock Lindstrom & Associates Ltd.

Auditor

Collins Barrow Calgary LLP
Chartered Accountants

Stock Symbol

The Toronto Stock Exchange – "TIV"

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Corporate Profile

Tiverton Petroleums Ltd. is an oil and gas exploration company with shares listed on The Toronto Stock Exchange ("TSX"), under the symbol "TIV".

Annual General Meeting

Shareholders are cordially invited to attend the Company's Annual General Meeting, which will be held at The Bow Valley Square, Hamilton Room, 3rd floor, 255 – 5th Avenue S.W., Calgary, Alberta, Canada on June 30, 2004 at 2:30 p.m.

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